Chapter Five – Distribution System Planning

I. Introduction

A utility's distribution system should be constructed so that growth in electrical load can be accommodated while maintaining system reliability. It may take anywhere from a few months to a few years from the time a utility recognizes the need for additional capacity in its distribution system to the time that the construction is complete and the system can accept the load. Therefore, it is critical to system reliability that the utility's planning is thorough and timely. Planning should combine known factors such as historical electric loadings and weather patterns with estimates of future conditions such as new customers additions and changes in customer usage patterns. This chapter presents the results of Liberty's review of ComEd's distribution system planning.

The objectives of Liberty's review were to evaluate ComEd's: (a) base planning assumptions, (b) reliability planning criteria, and (c) load forecasting process. In addition, the review assessed the overall effectiveness of ComEd's planning process and answered specific questions posed by the ICC Staff.

Liberty used the following evaluation criteria in the review of ComEd's distribution system planning:

(1) ComEd's overall distribution planning processes should have been consistent with good utility practices.

(2) ComEd should have considered all appropriate variables in the planning process and should have performed sensitivity analyses where appropriate.

(3) ComEd's distribution system load forecasting should have included all physical components that may have been limiting the provision of reliable service.

(4) ComEd should have had a reasonable distribution planning horizon (future forecasted period).

(5) ComEd should have reviewed the accuracy of prior forecasts and changed the planning methods as appropriate to better account for conditions that affected load.

(6) Distribution planning should include reliability guidelines or objectives that anticipate events that can reasonably be expected to occur.

(7) The distribution load forecast should be considered in budgeting processes.

Liberty found that while ComEd's organization of the planning function was reasonable, it did not use reasonable, conservative assumptions in making peak electrical load estimates and did not adequately reinforce its distribution system. Liberty provides its detailed conclusions and recommendations in sections III and IV of this chapter.

II. Background and Analysis

A. Organizational and Planning Process Overview

As of mid-1999, ComEd's distribution system planning was a centralized function responsible for forecasting the load growth in all of ComEd's regions. The primary areas of responsibility of the planning department were the main feeder, or "backbone," portion of the distribution system and the substation transformers that have a secondary voltage of 34kV or lower. ComEd divided its planning department into four groups. Two groups handled the feeders, the third was responsible for large projects, and the fourth was a small support group for areas such as load forecasting and long-range planning. The supervisors of each of these first three along with the fourth group reported directly to the Distribution Planning Engineer, who in turn reported directly to the T&D Planning Manager. This manager had over 30 years with ComEd and had been in a planning managerial role since 1992. The department consisted of about 42 people. The large majority of them had electrical engineering degrees.

On the basis of their electrical load forecasts and other factors, engineers in the planning department developed simplified designs for modifications and upgrades to the distribution system. The planners documented the designs as projects that included one-line conceptual drawings and written narratives that defined requirements and justified the modifications or upgrades. Planning then passed these projects to either the regional design engineering departments (for routine changes) or to the project management group (for projects that involved major modifications). Most of the projects had in-service dates that corresponded with the beginning of the summer load cycle. Typically, this date was June 1st of the year the improvement was required.

A cornerstone of system planning is the determination of the actual system historical loads. ComEd installed continuous operational monitoring of system loads in approximately 60 percent of its distribution substations. This load monitoring was generally performed through the Supervisory Control and Data Acquisition *(SCADA)* system. Substations without SCADA had chart recorders on the transformers and peak current metering on the feeders.

ComEd began the load gathering process by selecting several days from the most recent year that represented typical peak days. This process produced five or six specific dates that were then used by planners for historical load determination. Data gathering for system elements that had SCADA data available was straightforward. The other facilities required manual data gathering techniques such as reviewing strip charts and manually recording loads. The manual process can be hampered by problems such as recorder failure, use of an improper multiplier, lack of sufficient data resolution, or lost records.

ComEd's experienced planners trained new planners. They also developed a training manual that covered fundamental power engineering math, general electric system configurations, system protection, basic design, basic mapping, and the ComEd budgeting process. The book was an excellent reference for the listed areas of interest. It did not, however, address other fundamental planning responsibilities such as contingency analysis, maximum feeder loadings, the criteria to be used for connecting feeders to alternative sources, and project budget prioritization.

B. Load Forecasting

ComEd's load forecast cycle began in late August or early September after the summer peak had occurred. The projection was for five years and was formed on the basis of the most recent year's adjusted historical data. Two more historical years were displayed for each feeder and transformer for informational purposes. The goal of the five-year plan was to identify the distribution substation transformers and feeders that would become overloaded during the planning horizon of the forecast. The forecast included both "normal" and "emergency" seasonal ratings for transformers and feeder conductors. Planners attempted to move loads between feeders and transformers in order to optimize the loading. They attempted to keep feeders loaded at or below their summer "normal" rating so that, during abnormal situations, additional load could be placed on the feeders without exceeding the cable's "emergency" rating. When capital budget restrictions occurred, reinforcement projects were prioritized on the basis of relative loading factors to permit the most severe overloads to be addressed and provide the most value for available funding. When combined with the potential understatement of possible peak load conditions caused by ComEd's use of an "average" peak-day weather-load adjustment (discussed in detail below), ComEd created a burden its electric system could not bear under the pressure of severe hot weather.

When balancing loads did not resolve anticipated overload conditions, ComEd's planners developed conceptual design modifications and upgrades. The planners defined the needed in-service dates and produced cost estimates for each project, either by using rough approximations of typical costs or by requesting a formal design estimate from the design engineering department. Critical projects, those that were required to correct significant deficiencies, and small projects that could be completed quickly and economically, were processed first. The project diagrams for these projects were completed by the end of December of the current planning year. ComEd typically scheduled these projects for completion by the following June. For projects that were large in scale or less critical, planning completed designs by June of the following year and forwarded them to engineering.

Planning prioritized the projects and ComEd's management reviewed them. ComEd's annual capital budgeting process included a review of the cost estimates for these planning projects. Planning forwarded the completed and approved projects to Design Engineering or Project Management for final design and construction.

After the planning group completed its forecasts and project plans, and obtained management approval, it conducted an informal review with regional engineering and operations supervisors. ComEd did not distribute widely the results of the forecasts because it was a printed document that consisted of approximately 2,700 pages. This document was made available to ComEd's users (*e.g.*, dispatchers and customer project engineers) via its mainframe computer.

ComEd's forecast assumed both a base, or fixed percentage, growth rate and discrete new load additions to the system. The New Business department provided information regarding major new customers that would be added in the near future. ComEd used other data sources, such as developers' plans, business publications, and municipal zoning changes to gather data on likely future loads. Each individual planner reviewed the available information for his or her respective area of responsibility and compiled a hybrid combination of known loads and presumed growth rates. The ComEd load forecast then projected loads forward using the most recent year's weather-adjusted peak load as the basis. ComEd used this process for each feeder. ComEd forecasted transformer loads on the basis of the sum of the feeder loads attached to each transformer reduced by a historical coincidence factor.

ComEd used a SAS database to produce the feeder forecasts. SAS is a legacy mainframe spreadsheet-style program that was originally developed in the late 1970s to provide a "spreadsheet" environment accessible through mainframe terminals. ComEd used this system as the computational engine for performing distribution system feeder forecast calculations. The SAS-based tool is adequate to represent projected loads, transfers, and other feeder status information. However, the SAS environment had limited output capabilities and graphing options, and did not easily export or share data with other software or users. Moreover, it was inflexible, not considered user-friendly, and did not interface easily with other software. Over the years, ComEd added a number of subroutines to this forecast environment that assured complementary load transfers for Automatic ThrowOver *(ATO)* devices and load-relief switching.

A final step in the planning cycle was to perform load flow studies on the 34kV distribution system. These studies used computer models and software by PSSE. ComEd performed these operating studies to forecast the performance of its system as well as to alert operators of potential problems in the coming summer. Using data developed during the planning process, the PSSE program identified which 34kV lines may become overloaded. Planners reviewed the tested scenarios and went over them with System Operations. Planning also provided Operations with a list of potential problem feeders for which emergency switching procedures should be developed. Their goal was to allow the distribution system to be operated with minimal interruptions while construction of new projects was completed.

C. Weather Adjustments

Accurate load forecasting requires a sound correlation between electrical load and the effects of weather. The effect of weather on electrical system demand is a fairly well understood phenomenon. Whenever weather patterns, in particular temperature patterns, go to extremes, the effect on electrical load can be significant. ComEd's service territory is subject to both high and low temperature excursions. However, since 1958, the most significant season affecting electric system demand has been summertime. Other fuels such as natural gas, propane gas, and fuel oil temper the sensitivity of electricity consumption during cold weather. On the other hand, the vast majority of the cooling requirements in ComEd's territory were accomplished with electricity.

After data gathering, planners adjusted the load readings to account for any abnormal system conditions that may have existed at the time of the load peaks. These conditions included things like outages, temporary system configurations, and activation of automatic load transfer devices. Planners then normalized the load data on the basis of weather adjustment information provided by ComEd's Strategic Analysis department. Beginning in 1997, ComEd's distribution system annual peak load projections were "normalized" on the basis of the following weather factors: 1) the three-hour average temperature at the time of peak load, 2) the 8 AM temperature-humidity index on the peak day, and 3) the four-day lagged temperature-humidity index at the time of the peak and one, two, and three days prior to the peak. Because the "normalizing" process was based on the arithmetic average of historical peak-day data from the most recent 15 years (from

O'Hare Airport), it could be expected that the normalized loads would be exceeded on average 50 percent of the time or once every two years.

The process of using "normalized" load adjustments for the distribution system was an extension of a process that had been in place for a number of years for long-term forecasting of net system peak-hour demand used in generation planning and various financial forecasts. Because of the long-term horizon of these uses, "normalized" load projections were adequate. However, when the "normalized" strategy was extended to distribution forecasting, the effects of typical variation in the forecasted load from average conditions can cause a serious problem. Depending on the customer-class load mix on a specific feeder or substation, the variance between normal and severe weather can be significant. For residential areas, the distribution system load can increase by 13 to 25 percent above the normal values. The weather effect is less pronounced on the large commercial type loads with variations more in the range of 1 to 3 percent.

Liberty obtained weather information from the National Oceanic & Atmospheric Administration *(NOAA)* for Midway Airport, which is located in southwest Chicago, for the years 1928 through 1999. This location was selected because of its longer historical data availability. While these data did not permit the calculation of a four-hour moving average, a simple application of the daily maximum and minimum temperatures can be revealing. First, the median daily peak temperature of the ComEd summer load period was approximately 93°F. However, if only the months of June, July, and August are included in the evaluation, the median peak temperature increases to 94°F. When all summer months are compared on a monthly basis, July is the statistically the hottest. If only the month of July is considered for all years since 1928, the median daily peak temperature is 96°F. Therefore, half the monthly peak day temperatures in July are equal to or greater than 96°F.

During the summer 1999, ComEd had anticipated a system peak of about 19,500 MW. The actual peak, which occurred during the last week of July, was about 21,250 MW. The 9 percent deviation over the expected peak is especially significant when one considers the temperatures that ComEd's system experienced. The highest 5-day average of daily maximum temperatures during the 1928-1999 period was 99.8°F (37.7°C). During the summer of 1999, the highest 5-day average of daily maximum temperatures was 95.8°F (35.4°C), four degrees Fahrenheit cooler. The 99.8°F week occurred during a period (July 1995) in which ComEd's system experienced some of its most significant difficulties. However, the 5-day average in 1999 was only the 21st hottest such 5-day period in the 73 years for which data were available. Stated another way, the temperature conditions that occurred during the summer of 1999 are likely to recur about once every four years on the basis of historical 5-day maximum temperature data.

The effects of weather on peak loads are more complex than any one single parameter. The following table depicts the relative severity of the July 1999 summer with other significant summers. The numbers in the "Maximum Hourly Temperature" and "Degree Days Cooling" *(DDC)* columns are the relative severity ranking of that summer's heat measured as the consecutive 1-day, 3-day, and 5-day maximum hourly temperature or cooling degree days.

Year	Month	Maximum Hourly Temperature			Degree Days Cooling DDC			Heat Score	Heat Rank
		1 Day	3 Day	5 Day	1 Day	3 Day	5 Day		
1995	July	2	1	1	2	1	1	8	1
1988	July	7	2	6	6	4	12	37	2
1999	**July**	**5**	**7**	**21**	**1**	**2**	**4**	**40**	**3**
1988	August	18	14	4	7	5	2	50	4
1931	June	13	15	7	7	7	3	52	5
1988	June	4	3	5	9	10	24	55	6
1953	Sept.	16	5	2	21	6	7	57	7
1934	June	1	16	19	24	115	100	275	17

July of 1995 ranked first in relative heat severity. It had the hottest consecutive 3-day and 5-day peak hourly temperatures as well as the hottest consecutive 3-day and 5-day DDC requirement. It was second overall in both the 1-day peak hourly temperature and the 1-day DDCs. July of 1999 ranked third in relative severity. July 1999 had the highest 1-day DDCs on record with significant 3-day and 5-day DDCs as well. July 1999 had a relative maximum daily temperature ranking that was less severe. This table also indicates the importance of including the effect of DDCs into the temperature-load adjustment procedure. Notice that the hottest day on record, June 1, 1934 with a peak temperature of 107°F ranked only 17th in overall heat severity because of cooler night temperatures.

Liberty intends the preceding weather analysis and discussion to be illustrative and not exhaustive in its scientific thoroughness. A detailed review using hourly temperature data, hourly load information, DDC, and other weather indices such as relative humidity, wet bulb dew point, and solar radiation would be required to produce a reasonable model of the weather-induced effects on electric system load.

The use of a "normalized" or average peak-day weather adjustment, by definition, will cause half of the actual peak-day loadings to be exceeded over time. For system elements with design loadings approaching or even exceeding their load ratings, system overloads become very probable. When there exists an added burden caused by the failure of a system element (*e.g.*, underground feeder failure), the probability of insufficient distribution system capacity becomes high.

Liberty concluded that ComEd should change the way it makes electrical load weather calculations to reflect a more conservative approach.

D. System Design

Distribution system planning design begins with the distribution substation where transmission voltage (typically 138kV) or sub-transmission voltage (typically 34kV) is stepped down to distribution voltage (typically 12kV or 4kV). The planners were responsible for integrating new planned expansions or reinforcements with all the existing facilities. ComEd used several basic substation configurations depending on the load area being served. The following discussion is more technical than the rest of this chapter. However, it summarizes the design of distribution substations that Liberty found to be good for providing reliable service.

ComEd referred to one configuration as "Inside Chicago." This design focused on providing high capacity and redundancy. In the "ultimate" or "build out" configuration it contained four 30/40/50 MVA transformers, 8 distribution bus sections, 42 feeders, and 6 bus capacitor positions. Voltage control was provided by secondary load tap changers. Each group of six feeders was tied to an adjacent bus section via bus tie breakers. Four distribution bus sections were tied in a circular or "ring bus" configuration. The tie breakers were operated normally closed. This arrangement paralleled the secondaries of two - 50 MVA transformers. There was a normally open bus tie breaker between adjacent ring buses. Typically one bus is referred to as the "Blue" bus and the other as the "Red" bus. All breakers were rated 750 MVA fault duty. Line-to-ground fault current was limited by use of a common neutral grounding inductor. Line inductors were installed in series with the feeders to limit fault current. Older TDCs used what ComEd refers to as "bifurcating cabinets" where fewer feeder breaker positions are available. These cabinets were used to attach two separate feeders to one substation feeder breaker. One negative impact of bifurcating cabinets was the resultant higher number of customers concentrated on one feeder breaker resulting in a reduction of reliability to these customers whenever the feeder breaker was required to operate.

ComEd referred to the next TDC design as "Outside Chicago." This design focused on providing high capacity and moderate redundancy. In the "ultimate" or "build out" configuration it contained four - 24/32/40 MVA transformers, six distribution bus sections, and thirty feeders. Voltage control was provided by secondary load tap changers. Up to ten bus capacitors were paralleled with an equal number of feeder exits. Each group of six feeders was tied to an adjacent bus section via bus tie breakers. Three distribution bus sections are tied in a "straight bus" configuration. The tie breakers are operated normally closed. This arrangement paralleled the secondaries of two 40 MVA transformers. There was a normally open bus tie breaker between adjacent straight buses. All breakers were rated 500 MVA fault duty. Line-to-ground fault current was limited by use of a common neutral grounding inductor. Line inductors were not used in this configuration because of the reduced available fault current. Older TDCs used "bifurcating cabinets" where fewer feeder breaker positions were available.

Radiating from the distribution substations described above was the main feeder system. ComEd used multiple distribution feeder design configurations. They included:

- Radial Feeders – This design used both overhead and underground construction linked together serially and energized from a single point. The design normally included ties to adjacent radial feeders through normally open line switches.

- Underground Residential (URD) – This design was a form of the radial feeder design that used only underground distribution equipment (*e.g.*, cable, switch cabinets). "URD" is an industry acronym meaning "Underground Residential Distribution." Originally these systems primarily served residential subdivisions because of their aesthetics. So-called "URD" is now also used for commercial installations.

- Primary Selective (common and split-bus) – The common bus service used two independent primary sources that each fed one side of a single bus section through individually controlled switches. The "protected load" was tapped off the bus section. One source was designated the "preferred" feed and its switch (or sometimes breaker) was closed. The other source was designated the "alternate" feed and its switch (or breaker) was normally open. If the preferred source was lost, the system automatically switched from the preferred source to the alternate source. When the preferred source became re-energized, the system automatically returned the switches to their normal configuration after a predetermined time delay. This design was also referred to as an Automatic ThrowOver (ATO) scheme.

The split bus configuration was similar to the common bus ATO described above except that a third switch (or breaker) was added in the middle of the bus section with the load taps divided approximately equally between the two bus sections. In this configuration the two source switches were operated normally closed and the center bus switch was operated normally open. When either source was de-energized, the system opened the de-energized source switch and closed the center bus switch to quickly restore service to the affected half. When the lost source became re-energized, the system automatically returned the switches to their normal configuration after a predetermined time delay.

- Grid Network (also referred to as "low voltage AC network") – This system used multiple primary feeders dedicated to serving network loads electrically paralleled on the secondary side of the transformers to serve one or more load points. The system was generally the most reliable service available.

- Spot Network – This system is similar to the "Grid Network" described above except it was supplied by primary feeders that serve other single point distribution loads. This system was generally reliable except it was vulnerable to primary feeder imbalance currents flowing through the secondary bus and causing the network protectors to open.

- 4kV Network – Some 4kV systems were operated in network or parallel fashion to improve capacity and voltage regulation. Occasionally issues involving inadequate system protection occurred causing line faults to persist.

- Primary Loop – This system type generally was used in URD designs. The primary distribution feed was constructed in a loop configuration connecting serially or "daisy chain" fashion from one transformer to another. Each end of the loop was connected to a primary source and the approximate center of the loop was operated open. During system problems the center "open" position was closed and the affected section was isolated.

Each design was a different blend of capacity, redundancy, and cost. Each configuration was commonly used by the utility industry in similar load characteristic areas. ComEd's planners were generally involved in the decision process when a particular configuration was being selected.

When main feeders were being planned, the planners attempted to include feeder-to-feeder ties to provide alternate feed possibilities for both emergency and normal operational switching. ComEd planners did not have defined reliability criteria for determining capacity, frequency, or timing of the ties between feeders. These were left to the discretion of each individual planner.

"Steady-state" distribution voltages were mandated by the ICC at ± 10% for industrial customers and ± 5.8% for residential customers. The distribution planners designed the primary substation and feeder systems to maintain primary voltage between 100 and 105.8 percent of nominal.

Additional discussion on ComEd's system design is included in Chapter Six of this report.

E. Equipment Ratings & Loadings

Another cornerstone of distribution planning is the determination of the load carrying capability of each component in the system. Liberty's review of ComEd's process in this area focused on two important components in ComEd's distribution system: (1) transformers, and (2) line conductors and cables.

Thermal characteristics of equipment generally limit its load carrying capacity. The maximum capacity for each major equipment component is determined using standard heat flow models. The actual numerical determination of the component's capacity is not a planning function. ComEd's engineering standards and load rating books provided planning with detailed, specific data on the type of equipment, assumed load cycle, operating temperatures, and system operating conditions. These standards generally provided two ratings to planning, "normal" and "emergency." The ratings were further subdivided into two seasons—winter and summer—to recognize the typical ambient temperature differences during times of seasonal peaks.

"Normal" loading conditions meant that the system is operating in its usual configuration with all system elements in service. Under these conditions, equipment was not expected to exceed any critical temperatures. A component's materials (*e.g.*, paper, plastic, metal) generally control temperature limitations. Considering only electrical loading, if the maximum allowed temperatures are never exceeded, a device should last for many years. The lifetimes of most distribution equipment are assumed to be in the range of 30 to 40 years. Most equipment can achieve longer lives if the critical temperatures are never exceeded. It is not uncommon to find equipment that has been in service for 50 years or more.

"Emergency" loading conditions occur when one or more elements of the system are missing, either due to failure or forced removal such as from construction, weather, or an accident. Higher component loadings generally occur under emergency conditions, and they are permitted for limited periods. Emergency operating conditions often result in equipment temperatures exceeding the desired maximums. The long-term consequence of exceeding maximum temperatures is premature failure of the equipment—commonly referred to as "loss of life." Loss-of-life calculations are not an exact science. The electric industry has conducted a significant amount of research and experimentation to attempt quantification of this effect. When utilities operate equipment in the emergency range, they are accepting what should be perceived as a reasonable amount of loss-of-life. It is customary to find limitations on the amount and frequency of emergency loading conditions for various pieces of equipment.

On the basis of the criteria described above, the ComEd's planners selected the required capacity for each system component. This selection process was driven by the following factors:

- minimum capacity required to serve normal load
- system operational switching requirements
- planned normal maximum loading
- cost.

ComEd's distribution planners were responsible for monitoring and managing the actual planned loading on the distribution substation transformer and feeder systems. ComEd's feeder loading practice was to design the system to operate at less than 100 percent of normal capacity during peak loading conditions. In years when capital budget restrictions were more restrictive, the normal operating maximum was allowed to increase to 105 percent or even 110 percent. During the July 1999 events, many feeders were well in excess of 110 percent.

F. Use of Consultant Recommendations

Failure Analysis Associates *(FaA)* investigated a series of heat-related outages that ComEd experienced in July 1995. Two of the recommendations made by FaA concerned ComEd's planning practices. First, FaA recommended that ComEd's load forecasting methods be reviewed and revised to ensure that it used the maximum foreseeable ambient temperature for forecasting summer peak loads. Second, FaA recommended that ComEd initiate projects to reduce the load on (a) 12 kV distribution feeders before the load reaches 90 percent of a feeder's normal ratings and, (b) distribution transformers before they reach their maximum summer ratings.

Regarding the first recommendation, ComEd disagreed and did not increase its summer design temperature. ComEd believed that its summer design temperature was adequate and that there was no reason to make a change. Clearly, ComEd must have recognized that increasing the summer design temperature would have placed many components in its distribution system in an overload situation and that considerable capital improvements would have been necessary. As later events proved, the ComEd's decision to use the lower design temperature, and thus not make the required infrastructure improvements, reduced its ability to respond to system conditions and ultimately affected its system reliability.

ComEd also disagreed with the FaA recommendation to change its planning criteria for 12kV distribution feeders and distribution transformers. ComEd's planning criteria at the time was to load no individual feeder in excess of 100 percent of its rating. ComEd's planning criteria recognized the inadvisability of loading all facilities in an area to 100 percent since flexibility to handle new loads and outages would be limited. ComEd's own investigation of the summer 1999 outages showed that there were many overloaded distribution feeders that prevented switching of loads during contingency operations.

G. Planning Process Review

ComEd had no formal review or quality control for the results of its planning process. One aspect of planning that can have particular importance is the accuracy of load forecasts. Utilities may commit, or fail to commit, significant expenditures on the basis of load forecasts. If these forecasts are not accurate, capital expenditures may be misdirected or not made at all. A basic review should compare the accuracy of projected growth rates, historical peak load determination, and weather-load interdependencies with actual results. The only apparent review performed by ComEd consisted of subjective analyses by the planners and their supervisors.

A second critical area involves the analysis of events that cause equipment to be operated above their normal limits. As discussed above, when equipment is operated above its normal limits, excessive temperatures and the resultant degradation and loss-of-life usually result. Loss-of-life is an accumulating effect. The only way to judge such degradation is to track conditions that may lead to an alert that failure is likely.

ComEd operated some of its equipment above emergency thermal limits during emergency conditions. This practice was not unique to ComEd, although it was not widely practiced within the electric utility industry. Loss-of-life generally accumulates at an exponential rate when emergency ratings are exceeded. These incidents could have contributed to failures sooner than would otherwise be the case. In order to manage these potential events effectively, it is necessary to monitor, record, and accumulate the excesses, or loss-of-life events on major equipment such as large transformers and main feeder elements. Particularly close attention should be given to substation transformers and underground feeder mains because of their cost, replacement difficulty, and impact on large numbers of customers. Planners should be aware of equipment that may be nearing the end of its life in order to have contingency preparations ready if failure occurs. These preparations might include actions like pre-installing equipment, increasing the number of system transformer spares, and reinforcing field ties. Liberty found that ComEd did not formally monitor and document its equipment for loss-of-life events.

ComEd's management reviewed all project plans developed by the distribution system planners. First level management performed a technical review of the projects to insure they complied with ComEd's engineering standards. Depending on the total project cost, certain projects were routed through successive levels of management for approval. Projects up to one million dollars required approval by the vice president of Asset Management and Planning; projects up to ten million dollars required approval by the senior vice president; projects up to fifty million dollars required approval by the senior management committee; and projects over 50 million dollars required approval by the board of directors. The review process included a joint executive level review where total planning project dollars were compared and competed with the financial needs of other parts of the organization. If capital resources were limited, allocations were designed and agreed to by the various affected executives.

If capital expenditures are reduced below the amounts originally deemed necessary by the planners, certain projects must be redesigned, delayed, or eliminated. Often the result of these delays or deletions is that system loadings increase. A false sense of security can take hold during prolonged periods of cutbacks because the effects may not materialize immediately. The timing of a future catastrophic event is a function of weather, system loading factors, and luck. The analogy is the decision on when to change the engine oil in an automobile. The effect of a delay may not show up until years later when the automobile's engine fails. And just as ComEd's planners must look into the future for five years, the results of a decision to cut back on distribution system projects in say 1993, may not become apparent until 1998 or 1999.

ComEd's system loadings over the past ten years increased considerably both on transformers and feeders. To the extent that this increased loading increased the frequency or duration of events that caused equipment to operate above normal limits, the probability of failures increased correspondingly.

III. Conclusions

1. The organization of ComEd's distribution planning function was reasonable.

The centralized organizational design affords an excellent opportunity for intradepartmental communication on planning issues. The disadvantage of remoteness from the individual regions can be adequately compensated by good communications. ComEd's communication process included frequent visits to the region for face-to-face meetings with local engineering and operational personnel. However, better dissemination of annual forecasts may improve those communication channels.

2. Manual load information gathering methods were required for about 40 percent of ComEd's electric system. These methods were labor intensive and subject to human error.

Manual collection of essential operating data is time consuming and potentially inaccurate. Effective evaluation of manual data is frequently superficial or impossible. ComEd was making progress on the installation of SCADA system-wide. ComEd had developed a plan to implement SCADA on all of its distribution feeders. Therefore, assuming completion of the SCADA system as planned, Liberty does not have a recommendation associated with this conclusion.

3. ComEd's method of making electric load adjustments for the effects of weather was inadequate. (Recommendation Five-1.)

The correlation between system peak load and daily maximum temperature is a well established relationship. ComEd's use of a 15-year average peak-day weather load adjustment practically ensured that the assumed weather, and thus the electric load, would have a 50 percent chance of exceeding the forecast in any given year. The use of more conservative probability-based temperature-load projections allows more accurate forecast "worst case" loading scenarios. Accurate load forecasts are the foundation of system planning and design.

Following a series of disruptive outages in 1995, Failure Analysis Associates *(FaA)* was retained to evaluate ComEd's system and practices. One of FaA's recommendations was the adoption of a 99°F peak-day design temperature. However, ComEd did not agree with this recommendation (or several others made by FaA) and did not implement it. After the summer 1999 outages and ComEd's internal investigation, ComEd increased the design peak-day electric load weather adjustment from a "normal" peak day, which statistically would be exceeded 50 percent of the time to a 90 percent criterion that is statistically exceeded once every ten years. Based on Liberty's analysis of historical temperature data, adoption of this standard is certainly a step in the proper direction but still may not be adequate. Because electric energy has become a life-essential service, designing the electric system to sustain reasonably probable loads that may be imposed on the system is a necessity. Liberty recognizes that there is a trade-off between cost and reliability (*i.e.*, to build a system impervious to any weather event is not economically practical). The question of 'How good is good enough?' requires thoughtful study and mutual agreement among the parties affected.

For climates with significant variation in peak-day temperatures, the sensitivity of peak load to the daily maximum or minimum temperature is high. However, the effect of multiple, consecutive extreme temperature days is a secondary factor that can significantly affect peak-day loads as well. In addition, the effect of other variables such as relative humidity and solar radiation can have a noticeable and significant effect on peak-day loads as well as equipment ratings. Ignoring these secondary factors can cause the total forecasted peak-day load to be in error by 10 percent or more.

4. ComEd did not adequately reinforce its distribution system to supply reasonably expected loads. (Recommendation Five-2.)

Average distribution system loads were increasing on the ComEd system for the previous five years. Many feeders and substation distribution transformers had peak loads in excess of 90 percent under normal conditions. In fact, a significant number of these facilities operated at or above their seasonal "normal" 100 percent ratings during times of peak load. High average loadings leave insufficient or no operating margin for both normal operations as well as emergency operations. This situation was exacerbated by ComEd's adoption of a 105 percent, and sometimes a 110 percent overload standard for justifying new system reinforcement projects during periods of capital budget reductions. While using a higher overload standard is a reasonable way of prioritizing their most critical projects, this decision made the system ultimately vulnerable to failure during peak load conditions.

ComEd's planned loading practice did not allow sufficient margin for unplanned situations in which there was a single equipment failure event. When a major feeder element experienced an uncontrolled loss, the use of a 100 percent (or higher) loading factor created a high probability that there would be insufficient capacity on adjacent facilities to provide adequate relief. Underground cables do not tolerate heavy overload conditions for prolonged periods of time because their thermal mass is relatively small. Additionally, prolonged operation at elevated temperatures can cause the earth to dry and thermal runaway can occur. Because there is a natural reluctance to deploy forced outages to reduce loadings below damaging levels, facilities are commonly overloaded, sometimes even exceeding emergency maximum ratings. As described above, frequent or prolonged thermal overloads reduces the life of the affected facility and leads ultimately to its premature and untimely failure.

ComEd recently increased the summer design weather basis to that which would typically occur every ten years. ComEd initiated a significant number of projects required to prevent or relieve overloading made apparent by the higher design temperature. The number and scope of the projects was such that not everything that is required can be completed before the coming summer of 2000. As such, ComEd has prioritized the projects so that the most critical improvements would be completed first.

ComEd estimated that it will take about two to three years to complete all of the upgrades and additions identified as result of the new planning design temperature. This appears to be a reasonable estimate. The schedule-controlling factors are labor and materials availability. However, if ComEd adopts a more thorough examination of weather-related effects on its projected load, or if ComEd adopts a first contingency criterion to its planning methods, the current list of critical projects most likely will lengthen. (Liberty addresses the first contingency criterion in the recommendations that follow.) Nevertheless, it is noteworthy that it has been about five years since FaA made the original recommendation. Until the improvements are complete, ComEd's distribution system will be in a reduced state of reliability and unusually hot summers will increase the risk of additional outages.

5. **ComEd did not adequately upgrade, reinforce, or replace aging components of its distribution system.** (Recommendation Five-3.)

ComEd did not have a program to evaluate and replace aging components on its electrical distribution system. As previously discussed, most equipment will operate well beyond its normal expected economic life of 30 to 40 years if it is operated within its design specifications. However, two types of equipment degradation must be monitored and rectified.

The first, and most serious, aging effect comes from operating equipment such as cable and transformers above their normal ratings for extended periods of time. Each such event results in a reduction in the remaining life expectancy of the equipment. These events need to be identified and accumulated for the affected equipment. As the theoretical remaining life of the equipment is consumed, planning for upgrading, reinforcement, or replacement must be initiated proactively rather than reactively.

The second serious aging effect that must be monitored is general incipient failures that affect a class of equipment such as cross-linked polyethylene (XLPE) cable insulation treeing. Occasionally, equipment designs do not perform in the manner originally conceived. A specific example is 1970s vintage XLPE 15kV cable that is now beginning to fail relatively frequently due to insulation treeing. Remediation plans must be designed and implemented in advance of the actual failure.

6. **The distribution planning process lacked a formal, objective review process for accuracy of the load forecast processes.** (Recommendations Five-4 and Five-6.)

Many variables were included in the annual five-year load forecast. Lack of a formalized annual forecast review eliminated many opportunities for process enhancement and ultimately reduced system reliability and increased construction and operating costs. The lack of a review process contributed to ComEd mis-forecasting the load on many of its feeders and distribution substation transformers. If a forecasting process is working properly, deviations between forecasted values and actual values are identified and analyzed so that the processes can be improved.

The SAS-based forecast system made it difficult to make changes to procedural and computational processes used by the planning engineers. The planning group that forecasted distribution transformer loads transitioned to a PC-computer-based database program (Microsoft Access) for its forecast computations and report generation. This is a modern database program that is widely used, proven, and regularly updated. This program allows for relatively simple data input as well as data output to other programs and other users.

7. ComEd had only informal planning guidelines for relieving load on distribution feeders and transformers. (Recommendation Five-5.)

ComEd did not have a formal set of planning guidelines for determining when load remediation projects should be initiated for elements in the distribution system. In addition, ComEd had several other informal practices used by planning that should be made into policies. These included updating of all substations to include SCADA, replacement of severely overloaded equipment, and minimum design requirements for reliable power delivery such as contingency analysis, maximum feeder loadings, and project budget prioritization.

IV. Recommendations

Five-1 ComEd should justify the way it adjusts the historical peak electrical loads for 5-year forecast for weather.

ComEd's process for determining the effects of weather on peak-load demand before the summer of 1999 was based on a 15-year average peak-day weather adjustment. After the events of 1999 ComEd increased their weather adjustment to a 90th percentile adjustment. This would suggest that the forecast would be exceeded statistically once in ten years compared to once in two years. Liberty did not review this recent change in detail. While ComEd's change was certainly a step in the correct direction, it may not be appropriately justified. That is, ComEd should be able to explain why the weather adjustment should not, for example, be at the 95th percentile, which would equate to a prediction of exceeding the forecast once every 20 years.

As part of ComEd's evaluation of its weather adjustment criteria, a more sophisticated review of the weather-load relationship should be undertaken. This review should not only consider the weather variables currently in the model but also others such as degree-days-cooling, solar radiation, day of the week, and various variable integration periods. In addition, a sensitivity analysis of the preferred weather-load relationship should be conducted for each customer class as well as the system as a whole to assist in the risk analysis of the process. The results of this analysis should be included in ComEd's annual corporate load forecast publication to allow review and comment by the affected parties.

This is a medium priority recommendation that should be implemented by March 31, 2001.

Five-2 ComEd should implement a "First Contingency" criterion for its distribution feeder design process.

The use of a maximum design loading of 100 percent (or more) may not allow adequate reserve margin for unexpected weather anomalies, as well as both unplanned outages and scheduled operations. This depends on the assumed weather conditions and contingency design criteria. Most utilities use what is commonly referred to as a "First Contingency" basic design that attempts to allow adequate margin for the loss of the single, worst-case element in the distribution system. This critical element is usually either the loss of a substation transformer or a main feeder element, usually in the first mile of the feeder. Adopting this criterion would require that ComEd systematically analyze the design on the distribution system and determine what changes would have to be made in order that single-event failures could be accommodated by system switching without exceeding "normal" equipment ratings. Some utilities would rather use "emergency" ratings for their contingency analysis, but this frequently leads to capacity issues caused by elements of the normal system being out of service or reduced in capacity because of normal system activities like line construction and maintenance for periods of time that exceed the basic time-limit assumptions generally present in emergency rating analysis.

In no case should any element in the system be designed to operate above 100 percent of its "normal" rating when the system is in its usual configuration. The benefit of implementing such a criterion would be a more reliable electric delivery system. Anytime a system is operated above its "normal" capacity, loss of equipment life occurs. Frequent reliance on emergency ratings ultimately leads to untimely and premature equipment failures.

This is a medium priority recommendation that should be implemented by December 31, 2000.

Five-3 ComEd should develop a "Remaining Life" data base and review process that includes recording of overloading events, replacement plans, and a double contingency design under certain circumstances.

Most utility equipment is designed and installed in manner that allows it to operate for many years. However, operating and installation practices can shorten the expected life. In addition, some equipment does not achieve its expected life due basic design or manufacturing flaws.

ComEd's practice of routinely thermally overloading equipment reduced its life expectancy. Occasional overloading and its accompanying loss-of-life is an accepted utility practice. However, when these excursions occur, ComEd should record the events for significant circuit elements such as substation transformers and main feeder elements. As chronological age, combined with thermally stressed use degrade the remaining life of the facility, ComEd should implement plans for replacement or should develop operational alternatives. For instance, if a particular length of main feeder is approaching the end of its probable life, the "First Contingency" design factor may no longer be appropriate for the surrounding facilities. At that point, ComEd should go to a "Double Contingency" design where the loss of the degraded facility is automatically assumed as the first contingency. This strategy would allow ComEd to extract "all" the life from the facility before replacing it and without unduly affecting its customers.

This is a medium priority recommendation that should be implemented by June 1, 2001.

Five-4 ComEd should establish an annual, formalized, objective review of the distribution load forecast processes that quantifies the assumptions and the accuracy of the forecast for each projected year.

This review should include performance indicators for the relative accuracy of feeder load projections and transformer load projections. The review should include a written explanation of significant deviations in forecasted load and assumptions and the proposed remediation action. The review process would identify weaknesses in the forecast processes such as inadequate modeling of weather effects on electric demand and energy. A retrospective review would include a comparison of actual electric loads with remodeled (re-forecasted) loads using the actual weather parameters from the season being studied. Adaptation of such a review process will ultimately reduce both construction and operating costs and improve system reliability. Results of the review should be distributed to ComEd's management as well as the affected operating personnel.

The critical forecast variables include actual historical loads, actual weather conditions, assumed correlations between weather & load, base growth rates, and probable operating contingencies.

The review should include tabular as well as graphical results of the relative forecast accuracy for the last five years minimally. Additionally, statistical data such as standard deviations, confidence limits, and sensitivity analysis should be included.

This is a medium priority recommendation that should be implemented by December 31, 2000.

Five-5 ComEd should formalize distribution planning guidelines for determining when load relief should begin for circuits and transformers. In addition, ComEd should develop a formalized procedure for producing its annual five-year load forecast and budget review.

These guidelines should formalize as company policy that distribution feeders have the ability to accommodate a first contingency failure that requires switching of additional load onto a feeder without exceeding the seasonal "normal" rating of that feeder. Second contingency failures would then have the emergency rating available, thus significantly improving system reliability.

In conjunction with this policy, remediation projects should begin whenever the normal loading of a feeder approaches 90 percent of the seasonal "normal" rating. Projects to reduce the load on a feeder approaching 90 percent of it normal seasonal rating should begin far enough in advance such that the projects can be completed as the 90 percent mark is reached. The combination of these two planning criteria would greatly increase the ability of operators to switch loads without overloading circuits.

Liberty notes, however, that care must be taken in formulating these policies so that they are not overly restrictive. Planning, by its very nature, relies in part on the intuition and experience of the people doing the planning. Policies should provide a clear direction for keeping the distribution system in the proper condition for delivering reliable power. However, the policies should not prevent the person doing the planning from using his or her experience to override a policy that will not work in a particular circumstance. Deviations from a policy should be documented and justified so that, for example, other planners and management can understand why the deviation occurred.

The benefits of this recommendation are the more consistent application of reasonable policy and increased system reliability. Actual implementation of the policies in the distribution system could involve initial considerable costs since it represents such a significant deviation from past practice.

The five-year forecast procedure should specify the guidelines for data collection, weather assessment, and reliability planning criteria. In addition, the procedure should include a timetable for completing each significant milestone of the process such as weather adjustment, historical load determination, forecast completion date, project completion date, and historical forecast performance review.

This is a medium priority recommendation that should be implemented by March 31, 2001.

Five-6 ComEd should move from its SAS-based feeder forecast program to a state-of-the-art forecast computer environment.

There are several good options available to implement this recommendation. First, there are good load forecast software packages available on the market that are specifically designed to perform utility load forecasting. The benefits to this approach include:

- There exists a wide, common interest customer base that shares the same generic interests in the software.
- Computational techniques and error-checking have the review of a much greater number of users.
- Motivation by the vendor is high to improve and enhance the software.

A second approach is to use a commercially available database program. There are several choices that would be effective for ComEd. ComEd would have to develop (either themselves or through an outside contractor) a "program" that would use the database software in the manner appropriate for ComEd. The advantages to this approach are:

- The program can be customized to precisely fit the needs of ComEd.
- Data importing from other sources such as ComEd's SCADA system could be simplified.
- Data exporting to other applications and users is greatly simplified.
- The forecasts could be done on a PC allowing much greater ease in training and of operation.

This is a low priority recommendation that should be implemented by June 1, 2002.